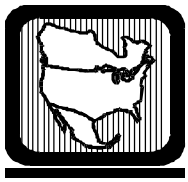


NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL
Princeton Forrestal Village, 116-390 Village Boulevard, Princeton, New Jersey 08540-5731

NERC Year 2000 Contingency Planning Guide Version 1.0

October 23, 1998

1.0 Goal

This document is a guide to Year 2000 contingency planning and preparations for the electricity supply and delivery systems of North America. The goal is to mitigate operating risks that could arise due to Y2k computer and other hardware logic errors, and to achieve reliable electric operations during the transition into the Year 2000 and beyond.

2.0 Scope

This guide is intended to address all aspects of electric power production, transmission, and distribution in North America.

3.0 Organization and Responsibilities

The effort of preparing electric systems for operation during critical Y2k transition periods must be coordinated at several levels:

1. NERC will coordinate contingency planning and preparations at the Interconnection and - interregional levels. NERC will review the contingency planning and preparations across all ten Regional Reliability Councils.

2. Regional Reliability Councils will coordinate efforts within their Regions and with neighboring Regions. This includes intra- and interregional studies and preparations and assuring participation of all members of the Region.

3. Members of Regional Reliability Councils that operate generation, transmission, or distribution systems (operating entities) will participate in this contingency planning and preparations program. These operating entities will coordinate contingency planning and preparations with their customers.

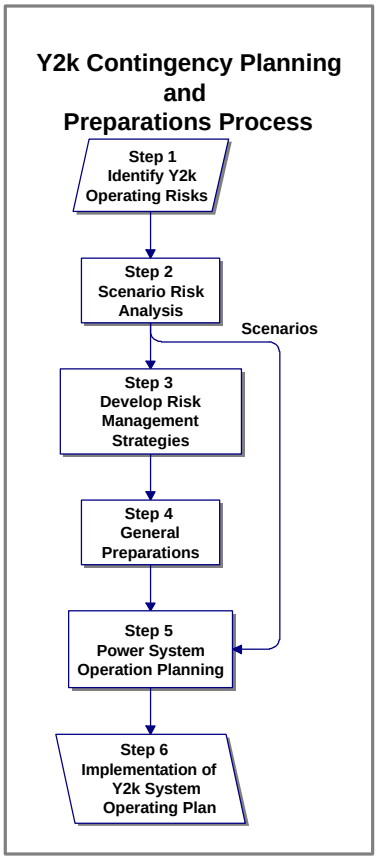
The NERC Y2k contingency planning efforts report to the NERC Board of Trustees through the Operating Committee and Security Coordinator Subcommittee. A Y2k Operational Preparedness Task Force reports to the Security Coordinators and serves as the primary coordinating body. Liaisons are established as needed to address commercial and technical issues. An organizational diagram is shown in Attachment 1.

4.0 Contingency Planning and Preparations Process

The following steps outline the process for Y2k contingency planning and preparations. These steps are intended as a general guide. Regions and operating entities are expected to develop contingency plans that meet their specific requirements.

Step 1. Identify Y2k Operating Risks – Identify sources of risk, both internal and external, that may impact the capability to sustain reliable operations into the Year 2000 and beyond. Examples of internal risks include loss or unavailability of generation, or loss of functionality within an energy management system. Examples of external risks include loss of leased communications facilities or reduced fuel supplies. For each risk source, estimate the probability

level and consequences of possible failures. A preliminary NERC Guide to Y2k Power System Operating Risks is provided as Attachment 2.



Step 2. Scenario Analysis – Analyze potential Y2k operating scenarios. It is not possible to identify and analyze all possible Y2k operating scenarios. Therefore, the recommended approach is to identify representative *More Probable Scenarios* and representative *Credible Worst Case Scenarios*.

The More Probable Scenarios are derived from the more likely Y2k risk sources identified in Step 1. These More Probable Scenarios should be analyzed and their priorities set based on probability and consequences. The analysis should identify the period(s) of vulnerability for each scenario. The Credible Worst Case Scenarios may be single cause or combined cause scenarios that represent the worst conditions that could reasonably be expected to occur.

The selection of the More Probable Scenarios and the Credible Worst Case Scenarios requires judgment as to the readiness and operability of facilities and backup systems through critical Y2k transition periods. NERC has provided examples of both More Probable Scenarios and Credible Worst Case Scenarios in Attachment 3. Coordination with Y2k Program Managers and technical personnel is important to understand the risks. A combination of tabletop analysis and computerized studies or simulations may be used for scenario analysis.

Step 3. Develop Risk Management Strategies – Develop strategies to mitigate the consequences of each of the More Probable Scenarios and Credible Worst Case Scenarios identified in Step 2. Risk management strategies can make use of staff resources, additional equipment and facilities (backup systems), special operating procedures (i.e. manual operation or use of backup communications), training and drills. Attachment 4 provides an outline of suggested risk management strategies as a starting point for consideration in Regional and operating entity contingency planning.

Step 4. General Preparations – This step includes efforts to prepare for and implement the risk mitigation strategies identified in Step 3. Preparations include development of special procedures; conduct of training and drills; procurement, installation and testing of backup capabilities; review and adaptation of restoration plans for Y2k conditions; and otherwise getting systems operationally ready for Y2k transition periods.

Step 5. Power System Operations Planning for Y2k – System studies should be performed based on the scenarios identified in Step 2 to determine appropriate reserve requirements, commitment of generation and transmission facilities, special system operating limitations, and operating strategies. The outcome of this step is a Y2k System Operating Plan.

Step 6. Implementation of Y2k System Operating Plan – The Y2k System Operating Plan is implemented in the final months, week, and days leading up to critical Y2k transition periods

and continuing through the critical periods. This step consists of the commitment, scheduling and management of resources according to the operations plan. This step also includes monitoring system conditions and responding to conditions according to the contingency response plans. This step would include system restoration and recovery operations if necessary.

5.0 Critical Y2k System Operating Dates

Part of the Y2k risk assessment process is to internally review the risks of Y2k anomalies for various dates. NERC-recommended dates for consideration are listed below in order of priority, from highest to lowest. It is important to recognize that critical transition periods may last only for minutes or hours due to primary causes (i.e. unit trips, loss of primary voice communications, etc.) or for days or weeks for secondary causes such as reduced supplies of natural gas, oil, or coal.

Priority 1 Dates

December 31, 1999 to January 1, 2000	Rollover to 2000: Date = 010100

Priority 2 Dates

February 28, 2000 to March 1, 2000	Rollover in and out of leap year date
September 8, 1999 to September 9, 1999	Special value: Date = 090999

Priority 3 Dates

December 31, 1998 to January 1, 1999	Special value: Year = 99
August 21, 1999 to August 22, 1999	GPS satellite clocks (EMS impact)
April 8, 1999 to April 9, 1999	Special value: 99th day of 1999

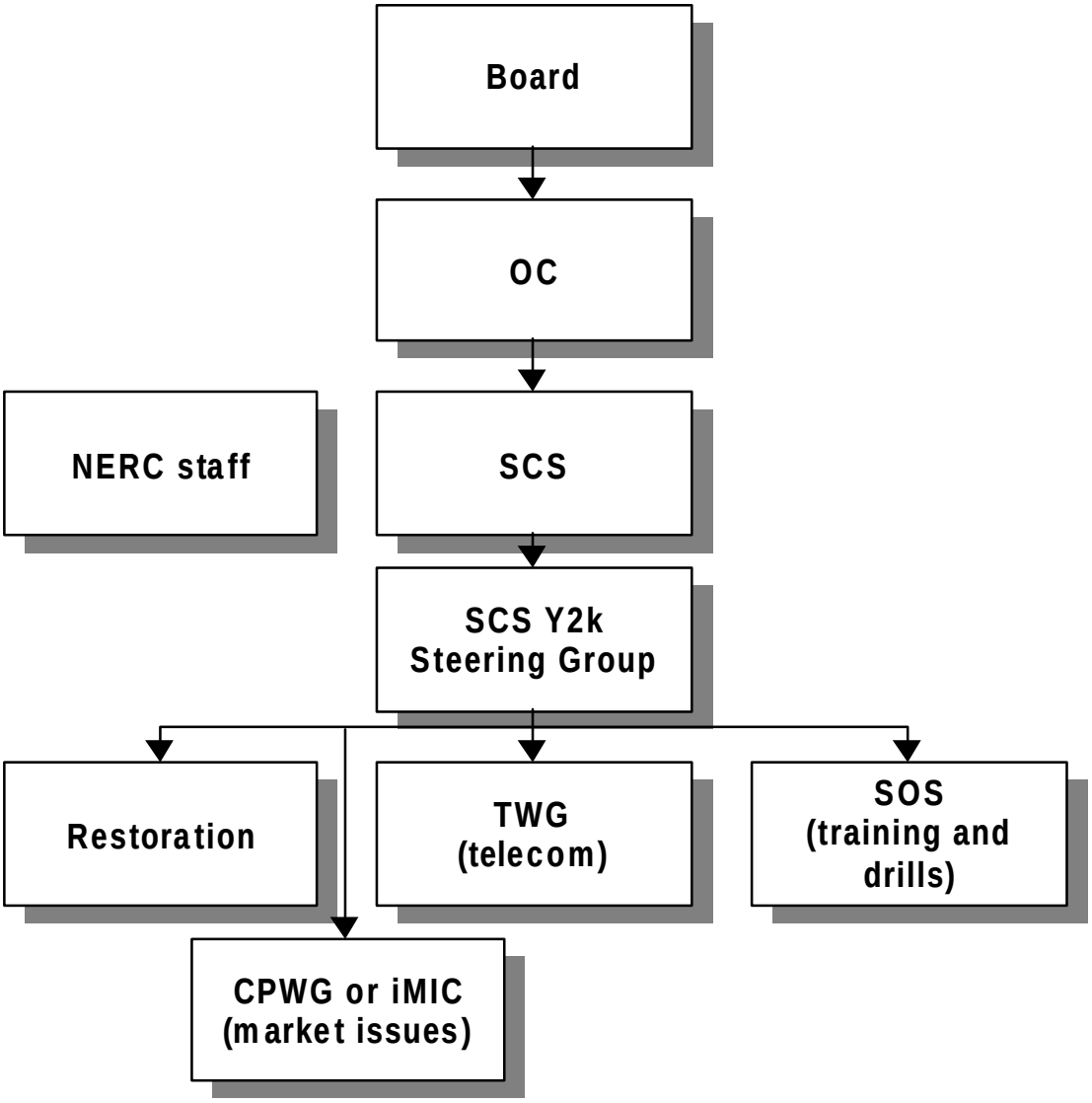
Other dates of operational concern that arise from Y2k test results should be considered as appropriate. Regional Reliability Councils and NERC should be notified of operational concerns for additional dates.

6.0 Schedule

The following milestones are applicable to this plan:

Date	Milestone
September 8, 1998	NERC initial draft contingency planning guide available
November 17-18, 1998	NERC Operating Committee approves contingency planning guide
November 19, 1998	Interim status report of Regional and operating entity contingency plan development
December 31, 1998	First drafts of Regional and operating entity contingency plans completed
January 4-5, 1999	NERC Board approves Y2K contingency planning guide
January 25-26, 1999	Regions report status of regional and member contingency plans
April 9, 1999	First industry-coordinated Y2k readiness drill
June 30, 1999	Second draft of Regional and operating entity contingency plans completed
September 8-9, 1999	Second industry-coordinated Y2k readiness drill

Attachment 1
Organization for NERC Y2k Contingency Planning and Preparations



Attachment 2
Y2k Risk Factors for Operation of Electric Power Systems

Disclaimer: None of the risks identified in this plan are predictions of Y2k events on electric power systems. The risks are assumed only for the purpose of planning and preparing for Y2k operations. The expectation is that implementation of this contingency planning process will mitigate these risks, with the goal of continuous and sustained delivery of electricity to all customers.

The following is a generic guide to serve as a starting point in the identification of Y2k system operating risks. Risks have been grouped into three tables: Table 1 - risks emanating from facilities owned, operated and maintained by the electric operating entity; Table 2 - risks emanating from external sources; and Table 3 - risks not directly caused by Y2k.

These NERC-assumed risks are offered as initial assumptions that have not yet been validated. These assumptions should be reviewed and adjusted on a Regional and individual company basis. A better understanding of actual risks is to be developed through coordination with Y2k Program Managers and technical personnel. These assumptions are expected to evolve as more details become available from Y2k testing and remediation.

Table 1 NERC Assumed Internal Y2k Risk Factors

Internal Risks	Period	NERC Planning Assumption	NERC Assumed Impact
Increased risk of generator trips/near coincident unplanned outages (includes - IPP generation); constrained output of units	Initial hours of Y2k roll over dates; may extend days	High probability of less than [10%]* loss of generation; low probability of [10%]* to [25%]* loss * These are initial NERC assumptions; actual values should be estimated by Regions and operating entities according to local conditions	High impact; location dependent impacts; concern is loss of more than reserve capacity
Inability to start or restart generators that are out for planned or unplanned outages (including IPP generation)	Inability to start generation may be over an extended period before and after Y2k dates	High probability of [15%]* or less unable to return to service as planned * These are initial NERC assumptions; actual values should be estimated by Regions and operating entities according to local conditions	Low to moderate impact; could be locally high impact
Constrained operation of nuclear plants	This constrained	Moderate probability of nuclear capacity reduced	Moderate depending on demand and reserves;

Internal Risks	Period	NERC Planning Assumption	NERC Assumed Impact
	operation may be over an extended period before and after Y2k dates	by [20%]* due to operational considerations * These are initial NERC assumptions; actual values should be estimated by Regions and operating entities according to local conditions	could be high impact on nuclear-heavy areas with constrained transmission
Increased risk of transmission facility trips/ near coincident unplanned outages	Initial hours of Y2k cut over dates; may extend days	Low probability of increased facilities tripping due to Y2k	High impact for multiple simultaneous outages; criticality is location specific
Control center physical access unavailable or uninhabitable conditions	Initial hours of Y2k cut over dates; may extend days	Low probability	Moderate impact on functionality if control center evacuation required
Partial loss of EMS/SCADA capabilities (including EMS overload during burst of high activity)	Initial hours of Y2k cut over dates; may extend days	Moderate probability of loss of some EMS/SCADA functions; moderate probability of loss of some RTUs	High impact due to loss of system data and control for critical functions; impact of communicating bad data is high
Loss of company-owned voice communications	Initial hours of Y2k cut over dates; may extend days	Moderate probability of loss of portion of company owned voice communications	High impact for partial loss of voice communications
Loss of company-owned data communication; includes real-time and non real-time data	Initial hours of Y2k cut over dates; may extend days	Moderate probability of loss of portion of company owned data communications due to high degree of networking and interdependence	High impact for partial loss of data communications
System protection (relay) failures resulting in system instability, cascading outage, or facility damage; remedial protection schemes failure	Initial hours of Y2k cut over dates; may extend days	Low probability of system protection tripping facilities; low probability of failure to operate when needed	High impact if failures do occur; results in facility trips possible cascading outages or facility damage
Load shedding (under-frequency and under-voltage load shedding) misoperate or fail to operate	Initial hours of Y2k cut over dates; may extend days	Low probability of inadvertent operation or failure to operate	High impact if failures do occur; large portion of loads susceptible to shedding; cascading outages; could be over

Internal Risks	Period	NERC Planning Assumption	NERC Assumed Impact
			generation condition if inadvertent load shedding with extra generation on
Load management systems misoperate or fail to operate	Initial hours of Y2k cut over dates; may extend days	Low probability	Low impact
Loss of or incorrect critical operating data, i.e. tie line meter data, plant data	Initial hours of Y2k cut over dates; may extend days	Low probability	Low impact
Failure or misoperation of HVDC tie or phase shifter	Initial hours of Y2k cut over dates; may extend days	Low probability	High impact, depending on location and configuration
Failure of environmental control systems	Initial Y2k cut over dates extending to days and weeks	Moderate probability of loss of some environmental monitoring systems	Moderate to high impact if loss of available generation more than reserves
Loss of security coordination systems or communications	Initial hours of Y2k cut over dates; may extend days	Low probability	High impact on communication and coordination
Loss of OASIS Node(s)	Initial hours of Y2k cut over dates; may extend days	Low probability	Low impact, may cause confusion in electric markets and affect market prices
Loss of distribution systems	Initial hours of Y2k cut over dates; may extend days and weeks	Low probability	High impact on locally affected customers; impact on bulk operations depends on the amount of demand lost
Availability of operating personnel and supporting staff due to holidays, transportation, scheduling	Days surrounding Year 2000 holidays	Low to moderate	Low to moderate
Voltage control devices misoperate/fail: transformers, capacitor switching; voltage regulators	Initial hours of Y2k cut over dates; may extend days	Low probability	Moderate to high impact on transmission operations

Table 2
NERC Assumed External Y2k Risk Factors

External Risks	Period	NERC Planning Assumption	NERC Assumed Impact
Loss of load	Initial hours of Y2k cut over dates; may extend days	High probability of some load loss; low probability of load loss sufficient to impact bulk electric operations	Low impact unless large amount of load is lost
Uncharacteristic load patterns	Days leading to and after Y2k roll over dates	High probability of unusual load patterns	Low impact; consider possible effects on system flows
Loss of leased voice, communications	Initial hours of Y2k cut over dates; may extend days	Moderate to high probability	High impact for coordinating operations
Loss of leased data communications	Initial hours of Y2k cut over dates; may extend days	Initial hours of Y2k cut over dates; may extend days	High impacts on protection, control, and monitoring
Pipelines constrain supply or pressure of natural gas	Days to weeks	Low to moderate probability	High impacts on power supply
Constrained supply of oil	Days to weeks	Low probability	High impacts on power supply
Rail systems constrain coal supply	Days to weeks or months	Low probability	Moderate short term; higher long term
Loss of supplies, including water	Days to weeks or months	Low probability	Low to moderate
Sabotage	Key Y2k dates	Low to moderate probability of incidents	Moderate to high for local impacts

Table 3
NERC Assumed Compounding Risk Factors

Compounding Risk	Period	NERC Planning Assumption	NERC Assumed Impact
Severe weather and cold weather	Days leading up to and after Y2k cut over dates	Moderate to high – varies locally or regionally	High impact on loads and system flows under severe weather

Attachment 3
Example Y2k Scenarios

Table 4

Examples of More Probable Scenarios with Potential for High Impacts
Loss or unavailability of [XXXX] amount of generation due to trips, unavailable to return from outage, or reduced ratings.
Partial loss of system monitoring and control functions, including data communications.
Partial loss of voice communications.
Loss of multiple transmission facilities.
Loss of load and/or uncharacteristic loads.

Table 5

Examples of Credible Worst Case Scenario Types
Combination of partial losses of generation, EMS/SCADA and communications.
Combination of facilities lost results in area blackout, including the following extenuating conditions: • Black start without communications/SCADA; some units won't restart • Sustained period of power loss resulting in batteries and other storage systems degraded • Unavailability of external resources for restart
Unplanned islanding of interconnection (interconnection restoration).
Long term loss of generation due to: • Loss of environmental monitoring and control • Loss of fuel supplies • Y2K maintenance/repairs
Loss of power supplies to critical facilities (nuclear plant, water treatment plant, sewage plant, hospitals, etc.)

Attachment 4
NERC Suggested Risk Management Strategies

Risk management strategies are designed to reduce the impact of the previously identified risks. To effectively prioritize strategies, the NERC assumed risk factors are plotted on axes of probability vs. impact. Mitigation strategies should focus on moving the higher impact risks toward the left axis (reduce impact). Y2k readiness efforts (testing and remediation) should focus on moving the risks toward the bottom axis (reduce probability of risks). Both efforts should be priority focused (start with risks in upper-right quadrant). A successful risk mitigation program across the industry will result in changes to this risk/probability chart.

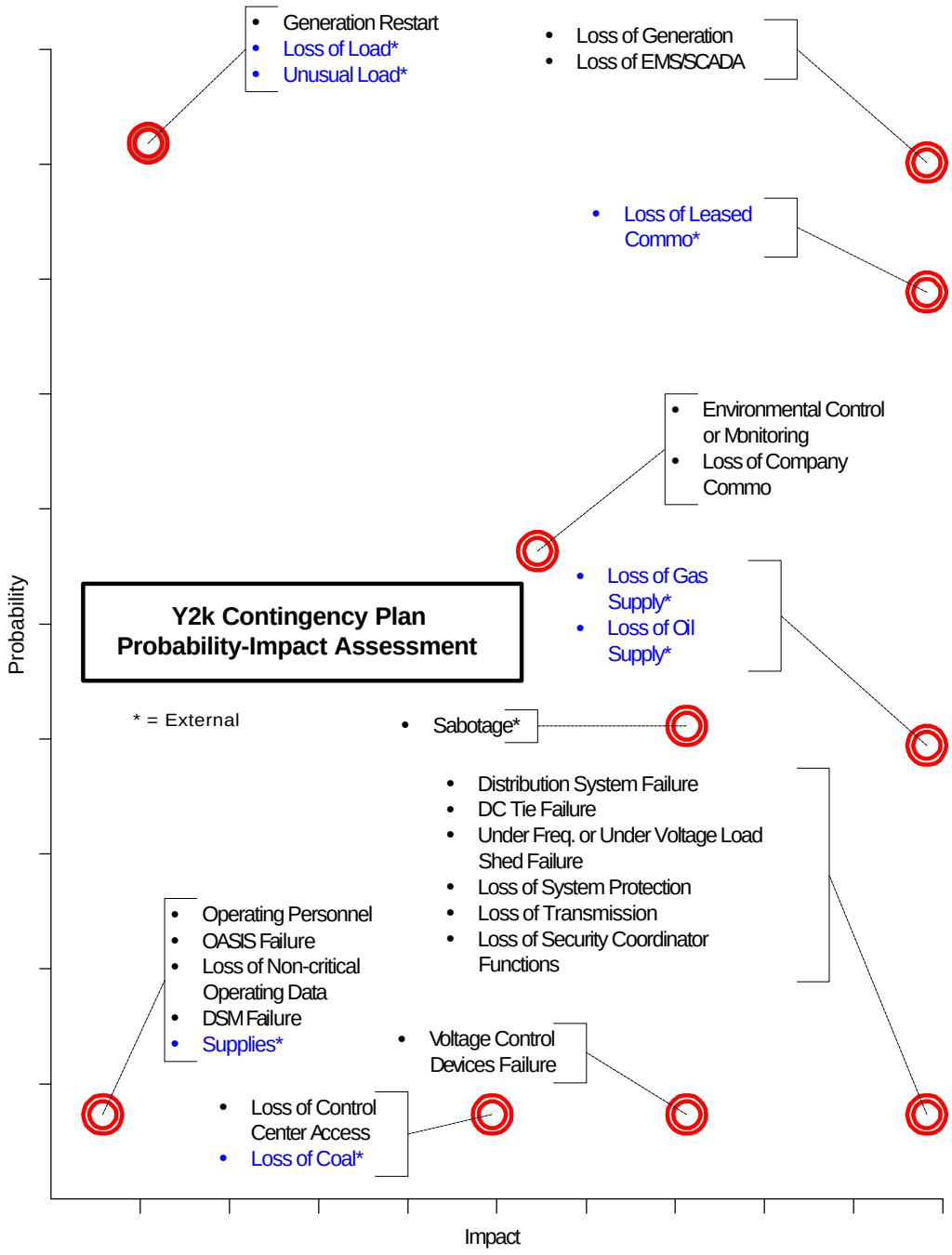


Table 6 offers a list of possible risk mitigation strategies for use in developing Regional and company contingency plans.

Table 6

Examples of Risk Management Strategies
• Additional spinning reserves and quick start units (older units less susceptible to Y2k) • Concern with location of reserves • Concern with minimum generation considerations • Minimize scheduled generator and transmission outages • Coordinate with market and IPPs for generation availability • Whole unit Y2k tests of critical units • Increase regulating capacity • Key technical support staff available on-site at critical transmission and generating stations and control centers • Load shedding plan ready • Black start capability and restoration plans ready • System studies of multiple, near-simultaneous transmission outages to look at thermal, voltage, and stability problems – operate within system operating limits; restrict transfers and interchange as needed • Communicate transmission mitigation strategy to the market (including possible reduction in transfers) • Operate systems interconnected (assume opening ties is last resort option only) • Control areas prepared to go on constant frequency control under islanding conditions • Units prepared to operate on frequency control • Backup radio systems tested and available • Identify, maintain and test older data systems that may be used as backup during Y2k, including power line carrier • Procedures and drills for operation without data and primary voice communication systems • Plan, test, and train backup voice communications for the following: – Control area to plant – Control area to transmission dispatcher – Transmission dispatcher to crews – Transmission dispatchers to wholesale customers – Control areas to wholesale customers and marketers – Control area to control area – Security Coordinator to control areas – Security Coordinator to Security Coordinator – Emergency center to emergency functions and services • Test backup power supplies for microwave systems • Control center contingency recovery plan (backup control center available) • Whole system testing of UPS, control center environmental controls • Identify manual monitoring and operating procedures, train personnel, conduct drills • Radio communications available as backup to primary voice communications to manual monitoring and control • Critical –information technology staff available to recover EMS/SCADA

Attachment 5
Sample Contingency Planning Template

The following template is recommended in the preparation of contingency plans. At a minimum, one template is recommended for each *More Probable Scenario* and *Credible Worst Case Scenario* analyzed. This example is simplified. It is expected actual plans would be completed in sufficient detail to provide a plan for implementation.

Plan No:	001	System(s):	Power Generating Units A, B, C, D, E, F, and G
Name:	Loss of Generation		Nuclear Generating Unit H
Type:	Credible Worst Case		

Risk Identification:

- Assume risk of loss of largest two units (1000 MW or 20% of system installed capacity)
- Assume nuclear unit operates derated to 80% capacity (400 MW) as precautionary measure
- Assume imports constrained to 500 MW
- Assume extended cold weather period December 29, 1999 to January 2, 2000

Scenario Description and Analysis:

- System peak loads are forecast to be 3800 MW December 29 and 30; 3400 for December 31 and 3100 for January 1 and 2; 3900 on January 3.
- Available capacity under worst case assumptions listed above is expected to be 3900 MW plus 500 MW imports.
- Assume operation with all steam units and nuclear unit on-line (4100 total); nuclear unit at 80% (400 MW); quick start units F and G (200 MW) off-line but available to start.
- Assume 500 MW imports available; requires assurances from neighbors; 500 MW imports are 33% of import capability – no loading problems anticipated.
- Minimum load on the morning of January 2 is expected to be 1800 MW; minimum generation requirements are acceptable with assumed units on-line (system minimum generation is 1700 MW at which point high voltage occurs in eastern part of system).
- Extenuating circumstances
  - Assume in January 3 morning load pick up largest two units are taken off line for unplanned maintenance (Unit A plus nuclear unit)
  - Assume one quick start unit fails to start when called (100 MW)
  - Assume neighboring system has problems and curtails imports to 0
  - Available capacity is 3900 MW; load forecast is 3900 MW

Expected Symptoms and Effects:

- Load obligations and system limits met through all peak and valley periods in assumed scenario until January 3 morning load pick up.
- January 3 peak load forecast at 3900 MW and available resources assumed at 3900 MW; 0 MW operating reserves possible under scenario assumptions.
- Further loss of resources or higher load would result in need to shed firm load.

Mitigation Strategies:

- Perform whole unit, on-line tests to minimize probability of loss of units.
- Arrange alternative external resources if available; coordinate with market regarding need for additional capacity on January 3.
- Conduct tests of quick start units to minimize risk of failure to start.
- Train system operators and plant operators for these conditions and possibility of a minimum generation condition.
- Appeal to customers to reduce non-essential loads on January 3.
- Review load shedding priorities and procedures; cold weather considerations.
- Notify authorities of conditions and coordinate response plan.

Implementation Plan and Schedule:

- Complete whole unit on-line tests by May 31, 1999
- Initial resource commitment and operating plan by September 30, 1999.
- Review preliminary load forecasts and resource commitment plan by November 15, 1999.
- Notify markets and neighboring systems of need for assistance by November 30, 1999.
- Notify local authorities of expected worst case conditions by November 30, 1999
- Complete final testing of quick start units by December 10, 1999
- Review final load forecasts and resource commitment plan by December 24.
- Implement resource commitment plan week of December 27.

Emergency Response Alternatives (Mitigation Strategies Fail):

- Implement voltage reduction plan for January 3.
- Be prepared to implement load shedding plan in the event load obligations cannot be met
- Notify officials of systems conditions as needed.

Verification (Approval)